BEFORE THE
ARIZONA CORPORATION COMMISSION

DIRECT TESTIMONY OF MARK E. FULMER

On Behalf of Constellation NewEnergy, Inc. and Strategic Energy, L.L.C.

Docket No. E-01345A-03-0437

February 3, 2004

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Attachments

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1. WITNESS BACKGROUND AND QUALIFICATIONS

Q: Please state your name and business address.

A: My name is Mark E. Fulmer. I am a Senior Project Manager at MRW & Associates, Inc. (MRW). MRW is an energy consulting firm that was founded in 1986 that specializes in power and gas market assessments, regulatory matters, litigation support, expert witness testimony, contract review, and negotiations. My business address is 1999 Harrison Street, Suite 1440, Oakland, California.

Q: Please summarize your professional and educational background.

A: I have been an energy consultant with MRW since 1999. During that time, I have worked with energy service providers, independent power producers, municipalities, end-use customers, trade organizations and financial institutions on a variety of issues related to industry restructuring, ratemaking, price forecasting, demand-side management and asset valuation. Previously, I worked at Daniel, Mann, Johnson, & Mendenhall (DMJM) in San Francisco, where I consulted to utilities and others on energy-efficiency. Prior to DMJM, I worked at Tellus Institute in Boston, Massachusetts, where I consulted to numerous state agencies and non-governmental organizations on integrated resource planning and natural gas and electric industry restructuring. I hold a Bachelor of Science degree in engineering from the University of

California at Irvine and a Master of Science in Engineering from Princeton University. See the Exhibit_MEF-1 for my resume and lists of my testimonies and publications.

Q: Have you ever testified before this Commission?

A: Yes. I testified in docket No. E-00000A-02-0051, which addressed the future of the Arizona Independent System Administrator. I have also submitted testimony before the FERC and state utility commissions in Hawaii, Pennsylvania and Rhode Island, as well as supporting testimony in ten other states and Canadian provinces.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of Strategic Energy L.L.C. (SEL) and Constellation New Energy, Inc. (CNE).[1] SEL and CNE requested that I examine Arizona Public Service's General Rate Case (GRC) filing and review the situation in other states where retail competition is thriving to identify what can be done in the context of this GRC to enhance competition in Arizona. This testimony presents my findings.

[1] SEL is one of the largest competitive retail energy providers in the United States, serving about 44,000 commercial and industrial customers in California, Massachusetts, Michigan, New Jersey, New York, Ohio, Pennsylvania and Texas. CNE is also a major competitive electric retailer, serving commercial and industrial customers in California, Delaware, Illinois, Maine, Massachusetts, Maryland, Michigan, Rhode Island, New Hampshire, New Jersey, New York, Ohio, Pennsylvania and Texas.

2. INTRODUCTION AND SUMMARY OF TESTIMONY[2]

Q: Is retail competition currently available in Arizona?

A: Yes and no. While retail competition is technically open in Arizona, because of the current generation credit afforded by Arizona Public Service (APS) to competitive retail suppliers, it has not occurred. However, this GRC can provide an opportunity for genuine retail choice to develop.

Q: Please describe the main thrust of your testimony in this proceeding.

A: First, actions in this proceeding should not impede the retail electricity market in Arizona before it is given a genuine opportunity to flourish. With an appropriate market design, electricity can follow in the footsteps of airline service, natural gas and other commodities that have successfully transitioned from price regulation to open markets. A guiding principle should be that price regulation is generally a poor substitute for a competitive market and that regulation is appropriate only in those limited circumstances where markets cannot function. While the transition to retail electricity markets has not always been smooth, it has been remarkably successful in many of the states where it has been implemented. Given an appropriate market framework and continued sound oversight by the Arizona Corporation Commission (ACC), it can be successful in Arizona, too.

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[2] I am aware of the opinion of Arizona Court of Appeals filed on January 27, 2004 in Phelps Dodge v Arizona Electric Power Cooperative. Since that opinion is subject to a possible petition for review and is not final, I have not assumed it to be in effect in this testimony.

Q: Do you have any specific recommendations?

A: Yes, I have three recommendations for the ACC with respect to APS's General Rate Case.

Q: What is your first recommendation?

A: My first recommendation is that if the ACC were to approve APS's request to include the wholesale generation assets of its affiliate in its rate base, that decision should not be allowed to be used as a pretext for eliminating or discouraging customer choice. In particular, costs associated with these assets should not at some future date be allowed to be characterized as "stranded" in the event customers select competitive providers. Even the threat of such stranded costs could effectively keep retail choice in its current dormant state. To preserve a competitive market, it should be clearly established that costs approved in this proceeding not be later declared as "stranded" as a result of retail market development.

Q: What is your second recommendation?

A: My second recommendation is that any new rate structures implemented here should not perpetuate the status quo of retail competition in name only. Specifically, revenue cycle service and transmission services provided by APS to direct access customers should be priced in a non-discriminatory fashion.

Q: What is your third recommendation?

A: My third recommendation is that a market structure be introduced in which commercial and industrial customers would purchase their commodity electricity products at market rates—either from APS or competitive retailers—while residential and small commercial customers would have the choice of regulated cost of service commodity rates from APS or service from a competitive retailer.

3. RETAIL COMPETITION IS PROVIDING BENEFITS IN OTHER STATES

Q: Has retail competition been providing benefits in other states where it has been implemented?

A: Yes. Competitive retailers now serve roughly 52,000 MW of load across the U.S.[3] This is larger than the load served by the New England, New York or California ISOs, and is approaching the size of the PJM Interconnection Regional Transmission Organization.[4] Figure 1 shows the retail load that had chosen alternative suppliers as of the middle of 2003.

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[3] KEMA, "Restructuring Report Card," January 2004.

[4] "PJM" initially stood for Pennsylvania-New Jersey-Maryland, the three states in which the RTO was initially formed. The RTO now includes all or parts of Delaware, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, West Virginia and the District of Columbia.

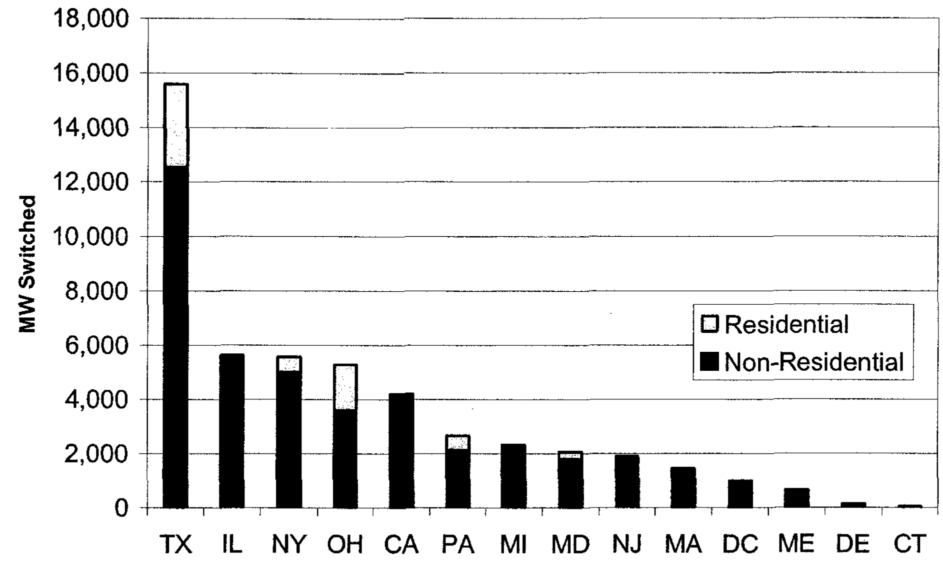

Figure 1: Load choosing competitive retail suppliers
Source: data from KEMA, "Restructuring Report Card," January 2004

The monetary savings to customers are significant. In Texas alone, the Public Utilities Commission estimated that "... retail customers have saved, at minimum, over $1.5 billion in electricity costs during the first year of competition [2002] as compared to the regulated rates in effect during 2001."[5]

Q: Are these states continuing to expand retail competition?

A: Yes. Many states with developing retail markets are expanding retail competition. Auctions for suppliers of default services to customers who do not choose alternative suppliers were recently completed in both New Jersey and Massachusetts, while Maryland is in the early stages of competitively selecting standard offer service

[5] Cover letter to the "Report to the 78th Texas Legislature: Scope of Competition in Electric Markets in Texas" Public Utility Commission of Texas, January 2003.

providers. This indicates a commitment by these states to build upon and expand the retail competition model. Maine has a notably robust retail market, with 60 percent of that state's larger customers choosing alternative suppliers. In Texas, the fraction is even higher: 85% of the state's larger customers have entered into contracts with competitive suppliers. In fact, the Maine experience has been so positive that the commission there has determined that third party provision should be the norm: "In market sectors where retail suppliers are providing options and reasonable prices for customers, standard offer service should not be 'just another supply option,' but should serve as a last resort or contingency service. By its design, standard offer service in these sectors should encourage and sustain customer out-migration to the retail market."[6]

Q: What types of customers are typically more likely to be in a position to select a retail power provider?

A: So far, most of the customers choosing competitive options have been commercial or industrial. This should be neither surprising nor disturbing. The savings to commercial and industrial customers make the effort of switching suppliers well worthwhile, while the more modest savings associated with residential and small commercial customers' energy bills makes the effort less appealing to those customers. But as retail markets evolve and as customers look for new ways to purchase energy services, the benefits of the experience of commercial and industrial customers can be transferred to small commercial and residential customers.

[6] "Standard Offer Study and Recommendations Regarding Service after March 1, 2005," issued by the Maine Public Utilities Commission December 1, 2002, page 4.

4. ARIZONA IS NOT CALIFORNIA

Q: Doesn't the crisis in California in 2000 and 2001 show that retail competition won't work in Arizona?

A: No. The electricity market and regulatory structures in Arizona, including the implementation of retail choice, are entirely different from the flawed structures in place in California during that state's energy market catastrophe. Arizona has the opportunity to build a fundamentally sound market, avoiding the problems seen in California. Furthermore, even though the California Public Utilities Commission (CPUC) closed retail choice to new accounts in September 2001, those who are eligible to retain competitive services are generally choosing to do so. I have little doubt that if the California Commission again allowed customers to choose competitive retail suppliers, many would do so. In fact, direct access load in California is currently about at the same level as it was at the beginning of the power crisis. Customers are pressing for the re-introduction of retail choice and a "core/non-core" approach has been proposed both in the Legislature and at the California Commission. This section outlines the major causes of the California crisis and shows that Arizona has sufficient safeguards to prevent similar problems from happening here.

4.1. CALIFORNIA OVER-RELIED ON THE WHOLESALE SPOT MARKET

Q: Please discuss the role of a spot market in wholesale electricity.

A: A well-operating spot market is an important tool for utility and non-utility electricity providers. Such a market provides both price discovery ("what is a kWh worth?") and a means to balance supply portfolios, selling excess power when available and making up any deficit as needed. A spot market is thus a valuable complement to longer-term supply procurement.

Q: How did the California investor-owned utilities use the spot market?

A. In California, from 1997 through 2000 the investor-owned utilities in the state procured virtually all of their resources at spot market prices. While there is disagreement on how much flexibility the California utilities actually had to enter into forward contracts during this period, the simple fact of the matter is that they were prevented from hedging (i.e., purchasing forward or using other financial instruments to guard against the risk of price volatility) a significant amount of their load. Due to risk of disallowances by regulators, they did not choose to hedge to the limited degree that they were allowed.

Q: What were the consequences of this over-reliance?

A: This over-reliance on the spot market had two consequences. First, when spot market prices were low, the utilities collected huge amounts to pay down their stranded costs. This was the intent of the California market structure. But when spot market prices increased, the utilities' exposure was also huge—on the order of tens of billions of dollars. Even without the market manipulation that is alleged to have occurred, the sheer size of the purchases in the spot markets meant that the utilities faced enormous risk.

Q: Is this flaw relevant in Arizona?

A: No. There is not now, nor has there ever been, a proposal to move all the state's power through a single-price market. The market disruptions that flowed from a flawed wholesale market structure are simply irrelevant in Arizona. Furthermore, these flaws were at the wholesale level. Third-party retail providers were caught up in the storm created by the flawed wholesale market just as the customers and utilities were.

4.2. FIXED RETAIL PRICES EXACERBATED THE PROBLEM

Q: How did utility retail prices contribute to the crisis?

A: It is clearly unsustainable for a retailer to promise to deliver a product at a fixed price without knowing how much it will cost to produce or acquire that product. In many markets, including energy, such behavior would be considered speculation, which is not a sustainable business model. Nonetheless that is exactly what occurred with the California investor-owned utilities (IOUs). The IOUs were required by statute to freeze their retail rates for four years while purchasing virtually all of their supplies on the spot market. As wholesale market prices rose in the last half of 2000, Californians heard in the news that electricity prices were skyrocketing, but would open their bills and see that retail rates were still fixed.[7] The bundled retail rate increases granted to the utilities in January and March of 2001 were simply too little, too late.

Even in the one case where the statutory rate freeze ended and retail customers could see the proper price signals (San Diego Gas & Electric), the legislature and CPUC backtracked and retroactively froze rates. Opportunities to allow greater forward contracting were delayed, effectively preventing the utilities from hedging. By the time state officials took concrete actions, it was too late—the IOUs were already defaulting on payments and the spiral down to insolvency had irreversibly begun.

4.3. RETAIL CHOICE WAS NOT PART OF THE CALIFORNIA PROBLEM

Q: Did the presence of retail choice contribute to the problems in California?

A: No. The presence of the retail choice element of the California restructuring plan did not contribute to the wholesale price run up or the eventual financial crisis. Retail choice, the companies providing retail services (Energy Service Providers or "ESPs") and the companies and individuals who chose retail providers were all negatively impacted by the crisis.

Q: During the crisis, many third party providers returned customers to the investor-owned utilities. Did that contribute to the problems?

A: No. Third party providers turning customers back to bundled service was not a major contributor to the California crisis. Under the California market structure, direct access

[7] This was initially not true for customers of San Diego Gas & Electric, who did directly see some of the early price

customers first paid their full bundled electricity bill, including the generation component. If the ESP was providing billing services, then the generation credit associated with the DA load was paid by the utility to the ESP; otherwise it was paid directly to the DA customer. As utilities struggled with high wholesale prices and frozen rates, they simply stopped paying the ESPs (along with the Qualifying Facilities and many other creditors). Under these circumstances many ESPs had no choice but to return the customers to the utilities who were not paying them; they could not pay their suppliers without being also paid by the utilities.

5. THIS RATE CASE CAN HELP OPEN UP GENUINE RETAIL COMPETITION

Q: Why hasn't there been an active retail market for power in Arizona?

A: The lack of interest by customers in selecting competitive retailers in Arizona has primarily been a function of simple economics stemming from the terms of the Settlement,[8] rather than a fundamental problem with retail choice in general. Simply put, the combination of a reduced bundled price and a low procurement credit for customers choosing a competitive retailer made it difficult or impossible to provide lower-cost alternatives to bundled APS service. This result should be no surprise: both competitive retailers and the ACC Staff pointed this out even before the Settlement was approved.[9]

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increases, but quickly had their rates retroactively re-frozen by the California Public Utilities Commission.

[8] Settlement Agreement entered into as of May 14, 1999, by Arizona Public Service Company and the various signatories for the purpose of establishing terms and conditions for the introduction of competition in generation and other competitive services.

[9] See ACC Decision 61973, page 6.

Q: How can this rate case change this situation?

A: The rates proposed in this application provide an opportunity to create a more competitive situation. Rates will be unbundled, so that the avoidable price alternatives will be transparent. The unbundled generation price is greater than the procurement credit currently afforded to potential direct access customers. As will be discussed, further consideration of pricing and market structures for larger, more sophisticated users will also help to capture the benefits of competition for Arizona electricity consumers.

6. APS MUST NOT CREATE "NEW" STRANDED COSTS

Q: Should the prospect of expanded retail competition be taken into account in this rate case?

A: Yes. Given that retail choice is the law in Arizona, and that the proposed rates in this application will significantly change the comparative economics of retail competition, ignoring the potential impact of retail choice would be short-sighted. Nonetheless, that is exactly what APS has done in this filing: APS assumes that no Arizonan or Arizona business will choose a competitive retailer.[10] While it is difficult to accurately project migration to competitive retailers, this possibility should have been discussed and the implications for cost recovery explored.

[10] For example, see APS response to CNE/SE 1-9.

Q: What is your major concern?

A: I am concerned that customers choosing competitive retailers might lead to APS claiming new or additional "stranded costs." This is especially important given the Company's proposal to acquire the generating assets of its affiliate, PWEC. If more customers choose competitive retailers than APS projects—which is likely, given that APS assumes that no customers will choose competitive alternatives—then APS will need to serve less bundled load. It is unreasonable for APS to not even *consider* a scenario where direct access load is nonzero in their planning. APS should not be allowed to rely on a flawed load projection today to claim stranded cost recovery at some future point.

Q: Is the notion of "future stranded costs" reasonable?

A: No; the notion of "future stranded costs" is an oxymoron. The concept of "stranded costs" refers to a claimed need for recovery of investments *already made* by regulated integrated utilities that can not be economically supported in a market environment. Stranded cost collection is a transition device to help move a regulated market to one that relies on competitive price signals. Once the stranded costs are paid off, or the time allowed for their collection elapses, they become irrelevant. Rather than force utilities to write off such excess costs (as would occur in a market), regulators have generally chosen to allow the utilities a one-time opportunity to recover these costs. Arizona is no exception, and APS has been afforded the opportunity to recover such stranded costs. But moving forward with the full knowledge that retail competition exists, there can be no reason for a utility to generate "new stranded costs." Investments made in the current regulatory regime are made for anticipated load, and will be recovered as this

Commission sees fit. There is no basis for incurring facility costs on behalf of customers who will not use those facilities.

Q: How has APS addressed new stranded costs?

A: Disturbingly, APS seems cavalier about these potential "new stranded costs." APS readily assumes it will recover all of its investment, one way or another. In discovery, APS was asked if it would request stranded cost recovery for PWEC assets if a large amount of retail load were to choose an alternative supplier (LCA 7.221, provided as Exhibit_MEF-2 to this testimony). It responded:

> The question assumes that customer choice is continued by the ACC — a matter currently under review by the ECAG. In any event, APS expects to have reasonable opportunity to recovery all its prudently incurred costs including the cost of its generation resources, plus a reasonable return... Whether those costs, under the assumption of your Question, are borne (partly) by departing direct access customers through a stranded cost recovery mechanism (in some future APS rate proceeding) or entirely by the remaining Standard Offer customers would be a decision for the ACC to make, although APS would recommend the former solution as being more equitable. (Response to LCA 7.221)

Q: What do you think about this response?

A: There are three elements to this response that are of concern. First, the response assumes that the ECAG review is the venue where the future of retail choice will be determined and seems to presuppose that the ECAG will determine that retail choice will be eliminated. However the ECAG is an advisory group of interested parties and not a regulatory forum. A rulemaking proceeding to consider any future recommendations made by the ECAG has yet to be opened. APS assumes that this advisory group will not only concur with its apparent position that customer choice should not continue, but also that a rulemaking will be opened to consider the ECAG's opinion, and that the ACC will act on it in APS's favor. Such assertions are presumptuous and should be disregarded.

Second, the response assumes that the PWEC generation resources are being prudently acquired. Given the weakness of APS's assumption that no customer will choose a competitive retailer, as well as other potential reasons that I have not investigated, and with no further analysis concerning the potential impact of customers exercising their right to choose competitive retailers, I cannot conclude that the acquisition of the PWEC assets is prudent.[11] Since APS has chosen to plan that no customers will take competitive retail service, APS's shareholders should bear the financial risk if the PWEC assets prove to be uneconomic.

Third, the response asserts that an exit fee would be the "most equitable" solution to APS's acquisition of generation resources that it did not know with any certainty it would need. In other words, APS would retroactively charge customers who lawfully exercised their right to select a competitive retailer for costs resulting from its own poor planning.

Q: Is it important to address the issue of future stranded costs in this proceeding?

A: Simply letting this issue lie unaddressed would have serious implications for direct access in Arizona. The threat of a new exit fee at some point in the future would create an unnecessary and unfair risk to Arizona businesses who will consider direct access service, and likely drive many away from doing so. Neither APS nor any other Arizona

[11] Constellation NewEnergy's position concerning the reasonableness of APS's acquisition of the PWEC assets on other grounds is presented in the testimony of the Arizona Competitive Power Alliance.

utility should be allowed to impose an exit fee simply because it under-forecasted direct access load when committing to long-term resources.

Q: Given your concerns about future stranded costs, what do you recommend concerning the treatment of the PWEC assets?

A: If the acquisition of the PWEC assets is found to be prudent, then I recommend that APS not be allowed to impose the costs of these generation assets via an exit fee on direct access customers who will not utilize or benefit from them. From Attachments SMW-3 and SMW-4 to the testimony of Mr. Wheeler, it appears that these assets should not be stranded. Attachment SMW-4 projects annual average growth in retail electricity sales in Arizona to exceed four percent per year. With this forecast load growth, if a few hundred megawatts of load choose service from competitive retailers, then these assets would likely still be utilized to serve APS's remaining bundled load and not be "stranded."

7. COMMENTS ON SPECIFIC RATE DESIGN PROPOSALS

Q: Please comment on unbundled rates.

A: In general, unbundled rates facilitate retail choice by providing clear price signals to consumers as to which costs and services must out of necessity be provided by the incumbent utility and which can be procured through competitive retailers. They also help prevent the commingling of costs among rate categories (e.g., so that costs more appropriately characterized as generation are not collected through the distribution charge). Nonetheless, care must be taken in assessing which costs are allocated to which rate category, as the shifting of costs from competitive components such as generation to non-competitive components such as distribution would send warped price signals to customers.

Beyond this broad observation, this section highlights a number of issues with respect to specific cost allocation and rate design proposals put forth by APS.

7.1. REVENUE CYCLE SERVICES

Q: Do you have any concerns about APS's rate proposal concerning revenue cycle services?

A: Yes. The proposed unbundled rates separate out services that APS sees as competitive from those which it sees as requiring monopoly service. I am concerned that for direct access customers APS proposes that revenue cycle services (RCS) be re-bundled with competitive generation supply services. The proposed rate schedules for larger consumption customers (e.g., E32, E34, E35) include the following:

> Direct Access customers must acquire and pay for ... revenue cycle services from a competitive third party supplier. If any revenue cycle services are not available from a third party supplier and must be obtained from the Company, appropriate charges will be applied to the customer's bill.

The simple interpretation of this language is that if any third party is offering RCS services—be they affiliated with a competitive retail power provider or not—direct access customers are obliged to take it. This reflects the current language contained in the Competition Rules.[12]

Q: What is your concern with this language?

A: Revenue cycle services can be competitively provided in conjunction with the selection of a competitive retailer of generation services, but this decision should be with the customer and its competitive retailer. Simply because a third-party supplier of RCS elements is offering its services in Arizona should not mean that a customer is obliged to use that supplier as a condition of acquiring its generation resources from a competitive retail power provider. The benefits of unbundling potentially competitive utility services such as RCS are maximized when customers have access to the broadest array of choices. A customer should be able to choose which provider of RCS best meets his or her needs at an acceptable price.

As it stands in Arizona, there is nothing stopping a third-party provider from requiring a customer to pay for RCS services that might in fact be inferior to those provided by APS. By forcing the potential direct access customer to use a third-party provider of metering and billing services, rather than allowing the customer to use utility-provided service, competition for both RCS services and competitive retail procurement services would be impaired and the customer harmed. Although this requirement of rebundling third-party RCS with competitive retail generation procurement is part of the current Competition Rules, an exception should be made here to allow direct access customers to be able to choose APS as its provider of RCS.

[12] See R14-2-1615B.

Q: What do the tariffs state concerning APS's provision of RCS to customers who select a competitive retail supplier?

A: The tariffs simply state that if APS provides RCS, "appropriate charges will be applied to the customer's bill." There are no elaborations as to what the "appropriate charges" might be, although in response to discovery APS notes that the "appropriate charges would be the unbundled values presented in the tariff."[13]

Q: Do you have a specific recommendation?

A: Yes. Direct access customers receiving RCS services from APS should pay the same rate for these services as standard offer customers. This should be explicitly stated in the tariffs instead of the vague "appropriate charges" language currently proposed.

7.2. TRANSMISSION PRICING

Q: Do you have any concerns with transmission pricing in APS's proposed retail tariffs?

A: Yes. In its proposed tariffs, APS also identifies transmission as a competitive service: "Direct Access customers must acquire and pay for generation, <u>transmission</u> and revenue cycle services from a <u>competitive</u> third party supplier." (emphasis added) For a customer in APS's service area, there is no competitive option to APS for transmitting power. Furthermore, transmission rates are not set by the market but are administratively set through FERC-regulated tariffs and thus can in no way be construed as "competitive."

[13] APS response to CNE/SE-1.9(b).

Q: How does APS address this?

A: In response to discovery, APS states that transmission service is the responsibility of the DA customers Scheduling Coordinator, which in turn is billed by APS at the Open Access Transmission Tariff (OATT) Rates.[14] APS further states that the Scheduling Coordinator for APS Standard Offer customers, presumably APS, receives service and pays for transmission service in accordance with the OATT.[15] APS's OATT contains a section that explicitly addresses power transmitted on behalf of direct access customers (Part IV).

Q: What are your concerns about this tariff?

A: My primary concern is that this tariff should continue to be administered and interpreted by the Arizona Independent System Administrator to assure that direct access customers are treated in a non-discriminatory fashion with respect to transmission. My second concern is that transmission not be characterized as "competitive" in APS's tariffs when, in fact, it is fully regulated.

7.3. POTENTIAL FOR COST SHIFT FROM GENERATION TO OTHER RATE COMPONENTS

Q: Please discuss cost shifting in the context of ratemaking.

A: A major goal of ratemaking is to appropriately assign costs. This is particularly true when costs have been unbundled on bills (e.g., distribution costs should not be paid for in

[14] APS response to CNE/SE-1.10(b).
[15] APS response to CNE/SE-1.10(c).

the generation component, etc.), and even more so when unbundled rates are combined with retail competition. In such a case, an incumbent utility, desiring to retain commodity customers, could shift costs that might more appropriately be characterized as generation into either the transmission or distribution rate component. Such a shift would make competition more difficult, as direct access customers would still be paying for the generation costs that have been shifted into transmission or distribution. This would be in spite of the fact that they are not receiving generation services from the utility or paying the "generation" component of the otherwise applicable rate. Furthermore, the generation "price to beat" component would be artificially reduced, making it all the more difficult for retail suppliers to offer economically viable alternatives.

Q: Have you examined the APS filing to determine if cost shifting has occurred?

A: No, I have not examined APS's cost allocation study or underlying workpapers to ascertain if any such cost shifts have occurred. I raise this issue simply to note that as APS has generally been critical of competition and shown a preference to retain Standard Offer customers, I believe it has the incentive to shift generation costs out of the generation component of large customer rates into non-competitive rate components. As such, special attention should be paid so as to prevent such cost shifts.

8. ALLOW A RETAIL MARKET TO TAKE ROOT

Q: What do you recommend concerning a market structure in Arizona?

A: As stated earlier, the natural evolution of the retail electricity market from administratively set rates to market-based prices has been successful elsewhere. I believe markets can provide benefits in Arizona, too. To that end, retail choice in Arizona should not be impeded by implementing rates or stranded-cost recovery policies that could artificially discourage customers from choosing competitive suppliers. In the longer run, the retail electricity market in Arizona should move towards genuine competition utilizing market pricing. In particular, Arizona can pursue a market structure in which commercial and industrial customers participate in a retail market, which could include APS as a competitive provider. Small commercial and residential customers could receive their power from a competitive supplier or could choose to remain APS standard offer customers with ACC-regulated cost of service generation rates.

Q: Does this market structure remove APS's obligation to serve?

A: Such a change would not remove APS's "obligation to serve" commercial and industrial customers. Instead, it would simply change how APS would procure resources for them. In such a system APS would enter into an appropriate portfolio of resources which would include both short-and long-term generation resources (i.e., short- to long-term contracts in addition to ratebased generating facilities) to serve the small commercial and residential markets. APS would generally use short-term market resources to serve the commercial and industrial sectors, charging these customers their procurement and procurement-related costs. APS could commit to long-term resources to serve commercial and industrial customers, however the retail rates charged to those customers would be market-based and APS shareholders would be liable if these market-based rates did not cover the company's procurement and related costs. This proposal is discussed further in Section 8.2.

8.1. CONTINUE RETAIL CHOICE

Q: Should customers' right to choose a competitive supplier in Arizona be limited?

A: The principle that Arizona customers have the right to acquire electricity from competitive retailers should not be compromised, either explicitly or inadvertently through policies that close the door to retail choice. However, I am concerned that APS may be actively pursuing policies that would stifle retail competition before it has a chance to genuinely begin.

Q: How do you see APS's filing in this proceeding stifling retail competition?

A: In this proceeding APS assumes that no Arizonan will choose a competitive retailer or that the right to choose a competitive retailer will be revoked. At the same time, it is sponsoring outside witnesses that endorse its plans of vertical integration, a framework not conducive to retail competition. As has been discussed here, this GRC may introduce a more genuine retail competition in the Arizona, a fact ignored by APS.

Q: Has APS been unreasonably critical of retail competition in other proceedings?

A: Yes. The prime example of this is at the Electric Competition Advisory Group (ECAG). In the Track A Decision (No. 65154), the ACC created the ECAG to, among other things, review and amend the Retail Electric Competition Rules. On March 19, 2003, in response to that directive, the ACC Staff issued a memo containing a set of questions to "to identify some of the key issues impeding competition and areas of the Retail Electric Competition Rules that could be improved" for interested parties to respond to. The intent of that memo was to generate constructive feedback as to how competition could be improved in Arizona. However, rather than responding constructively APS chose instead to use its response to suggest that the Commission revisit competition and to raise numerous reservations concerning retail choice in Arizona.[16] If the situation for retail choice and competition was even a small fraction as dire as APS characterized in its April 21, 2003 ECAG comments, then states with retail choice would be scrambling to return to full vertical integration as quickly as possible. But as outlined at the beginning of this testimony, that is not the case. States such as New Jersey, Massachusetts, Maryland, Maine and Texas are moving forward with retail choice, fully aware of the challenges but keeping their eyes on the benefits it affords their states' residents and businesses.

This proceeding should not introduce new impediments to retail choice, either explicitly or through setting rates and policies—such as recovery of new stranded costs from direct access customers—that would continue the competition-in-name-only situation resulting from the Settlements in 1998.

[16] "Arizona Public Service Company's Comments to the Electric Competition Advisory Group," April 21, 2003.

8.2. ALLOW THE MARKET TO EVOLVE AND MATURE

Q: Should the Commission be surprised or disturbed that a vibrant market cannot instantly be implemented in all customer segments?

A: Not at all. Experience elsewhere shows that the market most naturally evolves starting with the commercial and industrial customers who through declining average costs can more easily benefit from the flexibility afforded by retail choice. Once both customers and suppliers understand each other, products can be developed to better serve residential and small commercial customers.

Q: What important rate design characteristics do you find in the states where customer choice is flourishing?

A: An important rate design characteristic in the states where customer choice is flourishing is the phase-in of market-based rates for customer classes that are well equipped to make a choice about their energy provider. For example, New Jersey and Texas already set default service prices equal to market rates for some commercial and industrial customers. The Maine commission staff notes that "[s]tandard offer prices should closely track changes in the wholesale market, and other features of its design, such as treatment of customer credit, should parallel the market as much as possible."[17] Other states such as Massachusetts and Maryland have standard offer or provider of last resort prices based on competitive bids from unaffiliated wholesale providers. Such market-based pricing

[17] "Standard Offer Study and Recommendations Regarding Service after March 1, 2005," issued by the Maine Public Utilities Commission, December 1, 2002, page 4.

allows for more genuine competition for retail supply service, and its associated benefits, for those customers who can deal with such decisions.

Q: In this light, what do you recommend for APS?

A: APS should adjust its rate for commercial and industrial customers with peak loads over 250 kW, or aggregations of customers with a non-coincident peak load greater than 250 kW, such that the generation-related portion of those rates are based on APS's and short-term procurement and procurement-related costs used to serve these customers. APS would still have an obligation to serve these customers—that is, they could not be denied service—but it would not necessarily procure long-term resources on their behalf. Instead, APS would use shorter-term market resources to meet these customers' needs or it could choose to open this service to competitive bids, as is done in other jurisdictions.

Q: What about residential and small commercial customers with loads less than 250 kW?

A: Residential and small commercial customers with loads less than 250 kW should retain the right to choose alternative suppliers but should also have the option to purchase power from APS at ACC-regulated rates. This market structure would clearly define which customers APS would continue to have a long-term obligation to supply and which customers they would not. This would allow APS to plan its purchases with some certainty concerning its load and future obligation while still allowing customers to benefit from retail choice.

Q: What fraction of APS's total sales take service at 250 KW or more?

A: As Figure 2 below shows, customers with demand greater than 250 kW represent only about 22% of APS's total sales, or about 4.4 million megawatt-hours annually. This commercial and industrial segment also accounts for about 900 MW average non-coincident peak load, or 12.5% of APS's total average non-coincident peak load.

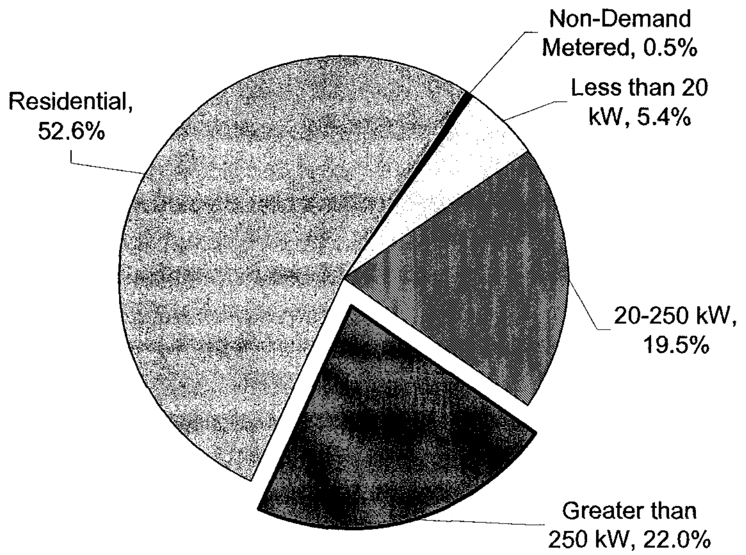

Figure 2: APS Energy Sales by Segment

Source: APS response to CNE/SE 3-1

Q: Does this mean that APS must divest its generation assets for this market structure to work?

A: No. Although market-based standard offer rates and utility asset divestiture have functioned well in other states (see Section 8), and were an integral part of the initial competition rules in Arizona, the fact of the matter is that for the near future APS will continue to own and operate generation. Given that reality, two fundamental policies should be observed.

Q: What is the first fundamental policy?

A: The first fundamental policy is that APS should not be allowed to collect costs associated with new investments that become "uneconomic" simply because customers exercise their right to choose a competitive retailer. APS knows the market structure in Arizona and is aware that customers might choose competitive retailers. Burdening such customers with APS's choice not to plan for such a possibility—even on a contingency basis—is unfair to those customers and could prevent the development of a competitive market in Arizona.

Q: What is the second fundamental policy?

A: The second fundamental policy is that APS should not set rates for the commercial and industrial customers in a predatory fashion such as through cost-shifting or special cut-rate contracts, so as to effectively prevent potential competitors from entering the market. As I have discussed, a good way to prevent this would be for APS to provide power to its large customers at market rates rather than having them administratively set via cost of service ratemaking.

Q: Is this an appropriate time to implement this bifurcated market structure?

A: I believe that it is a good time. Given the supply-demand situation that APS projects for itself, this is a good time to implement such a market-based system. Much of the load growth that APS is concerned with serving could be met by the market, leaving APS's ratebased assets to serve the smaller customers. Under such a structure, APS would not use ratebased generation assets to serve its large customers (or do so at its own risk), but instead would rely on short term resources to serve them. These costs would be passed through to the large customers APS would be serving. If APS did choose to use its ratebased assets to serve the large customers, then its shareholders would be responsible for any losses created by any difference between the market prices charged the retail customers and the imbedded cost of the ratebased generation.

9. EXAMPLES OF WHERE A BIFURCATED MARKET STRUCTURE IS IN PLACE AND FLOURISHING

Q: Where has a bifurcated market structure such as you are suggesting flourished?

A: The feasibility of the market structure discussed above in which commercial and industrial customers rely on the market for power while other customers are afforded greater protection has already been demonstrated. Both New Jersey and Texas have this bifurcated market structure, while other states such as Maine and Massachusetts intend enacting this structure within the next few years. Such a structure has existed also for over a decade with great success in California's natural gas market. Large gas consumers procure their own gas while the local distribution companies provide intra-state transportation services at regulated rates. Smaller gas customers take fully-bundled service from the utilities.

The remainder of this section presents some details concerning the New Jersey and Texas markets that not only demonstrate the feasibility of this structure but also its desirability.

9.1. NEW JERSEY

Q: Please describe the market structure in New Jersey.

A: On December 18, 2002, the New Jersey Board of Public Utilities issued a decision continuing the gradual phase in of electricity competition in the State.[18] To further this goal, the board created a new customer class common to all four of the incumbent utilities. This group of customers, known as the Commercial and Industrial Energy Price (CIEP) class, is comprised of 1,766[19] of New Jersey's largest electricity customers,[20] generally with peak demands greater than 1 MW.[21]

The Board then initiated a bifurcated supply auction for Basic Generation Service (BGS). The two auctions were held for Fixed Price (FP) BGS and Hourly Energy Price (HEP) BGS. Customers who are in the CIEP class and who do not select a competitive supplier pay the energy price determined in the BGS-FP auction. This is akin to a default service provided by the utility, but where Fixed Price customers can still gain some of the benefits of competition through the auction mechanism.

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[18] New Jersey Board of Public Utilities Dockets EX01110754 and EO02070384, Decision and Order issued 12/18/2002.

[19] Docket No. EO03050394, Decision and Order Issued 12/23/03, Page 1.

[20] PSE&G retail tariffs LPL-PRI, HTS-SUB and HTS-HV; JCP&L retail tariffs GP and GT; ACE retail tariffs AGS-TOU, AGS-TOU Subtrans.; Rockland Electric retail tariff SC7. PEPCO Energy Services. Presentation - Electricity Deregulation in New Jersey. Slide 10.

Q: What prices are paid by customers in the CIEP class?

A: Those customers who are in the CIEP class and who do not select a competitive supplier pay:

- The capacity charge determined in the BGS-HEP auction
- The PJM zonal real time hourly locational marginal price
- PJM OATT and Ancillary Service rates
- The Retail Margin (0.5¢/kWh)[22]

In addition, all customers pay the Default Supply Service Availability Charge (0.015¢/kWh) to the auction winners, as well as distribution and other charges to their local utility.

Q: Has the creation of the bifurcated system has proved successful in encouraging the development of retail competition in New Jersey?

A: I believe that it has. As of October 3, 2003, 860 of the 1,766 CIEP accounts, representing 67.8% of CIEP load, had chosen a competitive retail supplier.[23] In total, about 119,000 customers with combined load of over 2,400 MW have chosen competitive retail suppliers.[24]

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[21] PEPCO Energy Services. Presentation - Electricity Deregulation in New Jersey. Slide 9.

[22] The Retail Margin provides an incentive to choose a competitive supplier as well as to recognize the additional costs competitive suppliers must bear (e.g., marketing). New Jersey Public Utilities Board Decision, 12/18/02 Docket No.EX01110754 & EO02070384, pages 10 and 12.

[23] Docket No. EO03050394, Decision and Order Issued 12/23/03, Page 1.

[24] New Jersey BPU. Electric Switch Data, November 12, 2003. http://www.bpu.state.nj.us/energy/elecSwitchData.shtml

Q: Is New Jersey considering expanding the CIEP market segment?

A Yes. On December 23, 2003, the Board determined that all remaining customers with demand greater than 1.5 MW should be placed in the CIEP class, increasing the CIEP class by 128 accounts[25], or about 7%. This gradual transition keeps the migration of customers to CIEP manageable in size and ensures that the largest and most sophisticated customers are transferred first. The Board is also considering extending the CIEP class to include customers with peak demand greater than 750 kW.

9.2. TEXAS

Q: Please describe the market structure in Texas.

A: Texas's Senate Bill 7, passed in June 1999, established the market framework for the restructured electricity industry in Texas. This new market structure was instituted on January 1, 2002. A major feature of the Texas electricity market framework is the bifurcation of the market. Customers with a peak demand of one megawatt (MW) or more are no longer subject to Commission regulation or oversight with respect to generation-related transactions; these customers are free to choose among the variety of options available from competitors in the marketplace. Transmission and distribution services to these customers are still regulated by the Texas Public Utilities Commission. Within nine months of the opening of the Texas market, 85% of the commercial and

[25] Docket No. EO03050394, Decision and Order Issued 12/23/03, Page 2-3.

industrial customers with loads over one MW had entered into competitive retail contracts.[26]

Q: What does the Texas market structure say about expanding full competition into customers with loads less than one MW?

A: Customers with demand of less than one MW continue to have a regulated "price-to-beat" rate available until 2007, or until competitive suppliers have achieved a target market penetration. This latter trigger recently occurred for the small commercial market segment in two utility service areas. On December 18, 2003, the Texas PUC ruled that the 40% threshold had been met in the First Choice Power service area (North Texas).[27] On December 30, 2003, the Texas PUC made the same finding for TXU, the utility that serves the greater Dallas area.[28] This means that these utilities no longer are required to provide standard offer service, but instead are full competitive market participants in the small commercial customer segment.

Q: Has the market structure in Texas been successful?

A: The Texas program has generally been viewed well. Brett Perlman, a former member of the Texas PUC, noted that the opening of the Texas electricity market to competition has been the most successful deregulation plan in the nation.[29] Perlman also noted that by

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[26] *Texas PUC report to 78th Legislature* p. 76.
[27] "Texas drops power price limits for one company," Reuters News Service, 18 December 2003.
[28] "TXU freed to alter small-business rate Utility's customer loss reaches threshold set by state regulators." *The Dallas Morning News*, 31 December 2003.
[29] "Texan Declares Deregulation Program Successful," *Natural Gas Week*, 17 October 2003.

focusing on the largest consumers, the Texas market was able to ensure that power generators had the incentives needed to build in Texas.[30]

Q: Has anyone quantified the economic benefit to Texas of implementing this market structure?

A: Yes. The 2003 Texas PUC report to the Legislature also noted a recent study by Dr. Ray Perryman that quantified some of the initial economic benefits from electric restructuring during the first few months of competition in the state.[31] The Texas PUC report states:

> This study included Dr. Perryman's estimate of the total savings achieved by customers as a result of electric competition and the implementation of SB 7, as well as the economic benefits of consumers redeploying those savings to the purchase of other goods and services. The study estimated total benefits to the Texas economy from consumer savings at:
>
> - $716 million in annual total expenditures;
> - $350 million in annual gross area product;
> - $213 million in annual personal income;
> - $38 million in annual retail sales; and
> - 5,283 permanent jobs.
>
> Additionally, the study also estimated the aggregate effects of power plant development activity associated with competition since SB 7 was enacted. These benefits were found to be:
>
> - $32.4 billion in annual total expenditures;
> - $16.1 billion in annual gross area product;
> - $10.7 billion in annual personal income;
> - $4.1 billion in annual retail sales; and
> - 285,359 person-years of employment.
>
> *Texas PUC Report to 78th Texas Legislature,* pp 110-111

[30] Op cit.

[31] "The Truth About Electric Competition in Texas: An Early Assessment," *The Perryman Report,* May 2002, published by the Perryman Group. As cited in the *Texas PUC report to 78th Legislature,* p. 110

10. CONCLUSION: ACC CAN PROVIDE STRONG POLICY LEADERSHIP SIGNALING ARIZONA WILL ENCOURAGE COMPETITION WHERE IT BENEFITS RATEPAYERS

Q: What are your conclusions?

A: This rate case provides an opportunity to transition to a system that will allow genuine customer choice, rather than the choice in name only that occurred after the Settlements. This transition could be facilitated by:

- eliminating the threat of "new" stranded costs;
- ensuring direct access customers are treated in a non-discriminatory fashion in rates, in particular with respect to revenue cycle services and transmission; and by
- implementing a market structure whereby customer who are able to benefit from the ability to participate in a power market are able and encouraged to do so.

Q: Does this conclude your testimony?

A: Yes.

MARK E. FULMER

PROFESSIONAL EXPERIENCE

Senior Project Manager
MRW & Associates, Inc.
(1999 - Present)
Conducts and directs economic and technical studies in support of clients involved in regulatory and legislative proceedings, power project development and end-user energy option assessment. Work includes review of air emissions regulations and their impact on power costs; pro forma analysis of cogeneration and distributed generation facilities; economic analysis of end-use energy-efficiency projects.

Project Engineer
Daniel, Mann, Johnson & Mendenhall
(1996 - 1999)
Acted as project manager and technical advisor on energy efficiency projects. Work included management of PG&E program to promote innovative energy efficient technologies for large electricity users. Coordinated the implementation of an intranet-based energy efficiency library. Directed technical and market analyses of small commercial and residential emerging technologies.

Associate
Tellus Institute
(1990-1996)
Advised public utility commissions in five states on electric and gas industry deregulation issues. Submitted testimony on the rate design of a natural gas utility to the Pennsylvania Public Utilities Commission. Testified before the Hawaii PUC on behalf of a gas distribution utility concerning a competing electric utility's demand-side management plan. Analyzed national energy policies for a set of non-governmental agencies, including critiquing the DOE's national energy forecasting model. Developed model to track transportation energy use and emissions and used the model to evaluate state-level transportation policies. Developed model to track greenhouse gas emission reductions resulting from state-level carbon taxes.

Research Assistant
Center for Energy and Environmental Studies, Princeton University
(1988-1990)
Researched the technical and economic viability of gas turbine cogeneration using biomass in the cane sugar and alcohol industries. First researcher to apply "pinch" analysis and a mixed-integer linear programming model to minimize energy use in cane sugar refineries and alcohol distilleries.

EDUCATION

M.S.E., Mechanical and Aerospace Engineering, Princeton University, 1991
B.S., Mechanical Engineering, University of California, Irvine, 1986

Mark E. Fulmer
Prepared Testimony

1. Rhode Island Public Utilities Commission No. 2025
Prepared Testimony on Behalf of Rhode Island Department of Public Utilites and Carriers (Commission Staff). Testimony addressed the costs, savings, and cost-effectiveness of the proposed demand-side management programs of Providence Gas Company. April 1993.

2. Pennsylvania Public Utility Commission R-943029
Prepared Testimony on Behalf of the Pennsylvania Office of Consumer Advocate. Testimony reviewed 1307(f) filing of Columbia Gas of Pennsylvania, particularly the impact of the proposed gas cost recovery mechanism on residential customers. May 1994.

3. Public Utilities Commission of the State of Hawaii No. 94-0206
Prepared Testimony on Behalf of the Gas Company of Hawaii (Gasco). Testimony identification of Gasco's concerns regarding HECO's proposed DSM programs for competitive energy end-use markets. December 1994.

4. CPUC Rulemaking 01-10-024
Prepared Testimony on Behalf of the Alliance for Retail Energy Markets. Testimony addressed the utility procurement plans with respect to resource adequacy. June 23, 2003.

5. CPUC Rulemaking 01-10-024
Rebuttal Testimony on Behalf of the Alliance for Retail Energy Markets. July 14, 2003.

6. CPUC Rulemaking 01-10-024
Supplemental Testimony on Behalf of the Alliance for Retail Energy Markets. July 29, 2003.

7. Arizona Corporation Commission No. E-00000A-02-0051, E-01345A-01-0822, E-00000A-01-0630. E01933A-02-0069, E-01933A-98-0471
Rebuttal Testimony on behalf of Constellation NewEnergy, Inc. and Strategic Energy, L.L.C. Testimony addressed the future of the Arizona Independent System Administrator. July 28, 2003.

8. Arizona Corporation Commission No. E-00000A-02-0051
Rebuttal Testimony on behalf of Constellation NewEnergy, Inc. and Strategic Energy L.L.C. August 29, 2003.

Mark E. Fulmer
Publications, Reports and Presentations

1. ACalifornia: Crisis Over?@ Project Finance NewsWire. Co-author with Robert B. Weisenmiller, Steven C. McClary, William A. Monsen, and Heather L. Vierbicher. Chadbourne & Parke LLP. October 2001.

2. "Market Transformation Effect Indicators for Government, Utilities, Retailers and Manufacturers." Invited panelist in a roundtable discussion at the American Council for an Energy Efficient Economy (ACEEE) 1998 Summer Study. August 1998.

3. "Technical Assessment of Residential and Small Commercial Emerging Technologies." Prepared for Pacific Gas and Electric Company. San Francisco. September 1998.

4. "Evaluation of Food Processing Effluent Treatment Alternatives." Presented at the American Chemical Society meeting. Las Vegas. Co-author. December 1997.

5. "Carbon Taxes with Tax Reductions in Minnesota." Prepared by the Tellus Institute. Co-author. February 1997.

6. "New York Ecological Tax Reform Study." Prepared by the Tellus Institute. Co-author. June 1997.

7. "Strategies for Reducing Energy Consumption in the Texas Transportation Sector." Project for the Texas Sustainable Energy Development Council. June, 1995. Presented at: 75th Annual Meeting of the Transportation Research Board, Washington, D.C. Co-author. January 1996.

8. "Potential Energy and Cost Savings in the Transportation Sector of the State of Texas: Texas Multimodal Transportation Efficiency Study." Report for the State Energy Conservation Office on behalf of the Texas Sustainable Energy Council. Tellus Study No. 94-125. Co-author. June 1995.

9. "Comments on the DOE's Proposed Rulemaking Regarding Energy Conservation Standards for Three Types of Consumer Products: Including Fuel Cycle Environmental Impacts and Resource Depletion in a Societal Cost-Benefit Framework." Co-author. January 1995.

10. "A Social Cost Analysis of Alternative Fuels for Light Vehicles." Chapter 8 in Transportation and Energy: Strategies for Sustainable Transportation System. Daniel Sperling and Susan A. Shaheen, eds. American Council for an Energy Efficient Economy. Washington, D.C. January 1995.

11. "Resource and Compliance Planning: A Utility Case Study of Combined SO_2/CO_2 Reduction." Report Prepared in Cooperative Agreement with the U.S. Environmental Protection Agency, Acid Rain Division. Tellus Study No. 92-185. Co-author. October 1994.

12. "Misconceptions, Mistakes and Misnomers in DSM Cost-Effectiveness Analysis." ACEEE

1994 Summer Study. Pacific Grove, California. Co-author with Biewald. August 28-September 2, 1994.

13. "An Evaluation of Kentucky-American Water Company's Long-Range Planning." Report for the Utility and Rate Intervention Division, Kentucky Office of the Attorney General. Tellus Study No. 94-097. Co-author. June 1994.

14. "National Climate Change Policy and Clean Air Act Compliance: A Case Study of Combined CO_2/SO_2 Reduction." Proceedings of the National Association of Regulatory Utility Commissioners' Fifth National Conference on Integrated Resource Planning. Kalispell, Montana. May 15-18, 1994

15. "Economic Opportunities Through Energy Efficiency and the Energy Policy Act of 1992, for Environmental Improvement and Energy Resources Authority." Report for the Missouri Legislature, pursuant to House Concurrent Resolution 16. Tellus 93-166. Co-author. December 1993.

16. "Research on Carbon Emissions Associated with Clean Air Act Compliance." Progress Report for Tasks 1 and 2. Tellus Study No. 92-185A2. Co-author. September 1993.

17. "A Social Cost Analysis of Alternative Fuels for Light Vehicles." Presented at the Transportation and Energy Strategies for a Sustainable Transportation System conference. Pacific Grove, California. Co-author. August 22-25, 1993.

18. "IRP Concepts and Approaches." Report for Hydro-Quebec, and the Public Interest Groups and Associations. Tellus Study No. 92-155. Co-author. July 1993.

19. "Applying an Integrated Energy/Environmental Framework to the Analysis of Alternative Transportation Fuels." Invited paper at the European Council for an Energy Efficient Economy (ECEEE) 1993 Summer Study. Co-author. June 1993.

20. "Integrated Resource Plan Report. Volumes 1 and 2." Before the Public Utilities Commission, State of Hawaii. Tellus Study No. 92-181. Co-author. May 1993.

21. "Trash, Traffic and Taxes: Elements of Market-Based Pollution Policy." Report for Pace University Center for Environmental Legal Studies. Tellus Study No. 92-148. Co-author. May 1993.

22. "The Role of Gas Heat Pumps in Electric DSM." Presented at the Sixth National Demand-Side Management Conference. Miami Beach. March 24-26, 1993.

23. "Evaluation of Cost-Effective Fuel Switching for Residential Space Heat in Maine." A draft report for the Maine Public Utilities Commission Staff. Tellus Study No. 92-063. Co-author. January 1993.

24. "The Environmental Impacts of Demand-Side Management Measures." EPRI report TR-101573. Tellus Study No. 92-089. Co-author. December 1992.

25. "Natural Gas Planning: An IRP Case Study." Presented at: the National Association of Regulatory Utility Commissioners' Conference on Integrated Resource Planning. Burlington, Vermont. Co-author. September 13-16, 1992.

26. "Natural Gas Vehicles from an Integrated Resource Planning Perspective." Presented at the Eighth National Association of Regulatory Utility Commissioners' Biennial Regulatory Information Conference, Columbus, Ohio. September 9-11, 1992.

27. "Direct Environmental Impacts of Demand-Side Management." Invited paper at the American Council for an Energy Efficient Economy (ACEEE) 1992 Summer Study. Co-author. September 1992.

28. "The Analysis of Residential Heat Pumps as a DSM Measure from an Integrated Resource Planning Perspective." Report for the American Gas Cooling Center. Tellus Study No. 91-265. Co-author. August 1992.

29. Evaluation of Public Service Electric & Gas, Demand-Side Management Resource Plan (Electric)" Submitted in Docket No. Ex-90040304 to the Rate Counsel Division, Department of Public Advocate. Tellus Study No. 92-055C. Co-author. June 1992.

30. "Evaluation of the Application of Aquidneck Power Limited Partnership to Construct an Energy Facility in Portsmouth, Rhode Island." Report for the Rhode Island Division of Public Utilities and Carriers; the Governor's Office of Housing, Energy and Intergovernmental Relations; and the Department of Administration/ Division of Planning. Tellus Study No. 91-255. Co-author. April 1992.

31. "Management Audit of ARKLA, Inc., Regarding Its Compliance with the Least-Cost Purchasing Statute of the State of Arkansas." Report for the Staff of the Arkansas Public Service Commission. Tellus Study No. 91-080. Co-author. February 1992.

32. "Preliminary Study on Integrated Resource Planning for the Consumers' Gas Company, Ltd." Report for Consumers Gas Company, Ltd. Tellus Study No. 91-001. Co-author. January 1992.

33. "Bristol and Warren Gas Company Evaluation of Gas Supply Strategy and Costs." Exhibit 1 of Direct Testimony of Richard Hornby in Docket No. 1727, submitted to the Division of Public Utilities and Carriers, State of Rhode Island and Providence Plantations. Tellus Study No. 90-135. Co-author. June 1991.

34. "The Environmental Costs and Benefits of DSM: A Framework for Analysis." Prepared for EPRI. Tellus Study No. 90-177. Co-author. January 1991.

35. "The Co-Production of Electricity and Ethanol from Sugar Cane: A Technical and Economic Assessment." Masters' thesis and Center for Energy and Environmental Studies Report. Princeton University. January 1991.

36. "Cogeneration Applications of Biomass Gasifier/Gas Turbine Technologies in the Cane Sugar and Alcohol Industries" Proceedings, Energy and Environment in the 21st Century. MIT Press. Cambridge, Massachusetts. Co-author. 1990.

37. "A Technical and Economic Assessment of the Co-Production of Electricity and Alcohol from Sugar Cane." Proceedings, IECEC-90, IEChE. New York City. Co-author. 1990.

LACAPRA'S SEVENTH SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPORVAL OF PURCHASED POWER CONTRACT E-01345A-03-0437

LCA 7.221 If the PWEC units are ratebased as a result of this proceeding, and in 2005 a large amount of APS retail load were to choose an alternative supplier, would the Company request stranded costs associated with the PWEC units?

RESPONSE:

This question assumes that customer choice is continued by the ACC – a matter currently under review by the ECAG. In any event, APS expects to have a reasonable opportunity to recover all its prudently incurred costs including the cost of its generation resources, plus a reasonable return. In that regard, it does not make any difference whether that generation cost is for the PWEC units, APS' now-existing generation, or a long-term purchase power agreement. Whether those costs, under the assumption in your Question, are borne (partly) by departing direct access customers through a stranded cost recovery mechanism (in some future APS rate proceeding) or entirely by the remaining Standard Offer customers would be a decision for the ACC to make, although APS would recommend the former solution as being more equitable.

Witness – Alan Propper